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Development of type curves for gas production from horizontal wells in conventional reservoirs

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Development of Type Curves for Gas Production from Horizontal Wells in Conventional Reservoirs

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ABSTRACT

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Abdullah M. Almansour

As the demand for natural gas has increased in the recent years, the need for forecasting reliable gas recoveries has also increased. Gas production type curves are one of the methods utilized to estimate future well performance.

The objective of this research has been to develop and evaluate production type curves for horizontal wells producing from natural gas conventional reservoirs. These curves can be used to predict the production performance for horizontal wells during preliminary evaluations, thus avoiding the need for costly and time consuming computer simulation.

Two set of type curves were developed using a finite-difference multi-layers reservoir model. They represent the two flow regimes associated with the horizontal wells, the early time liner flow and the late time pseudo-radial (elliptical) flow. They were presented in terms of dimensionless gas production and dimensionless time. Drainage shape was assumed to be rectangle since it is the more effective drainage area for horizontal wells. The dimensionless well length, the ratio of well length to reservoir length and pressure drawdown dimensionless parameter *Xi* were found to influence the type curves significantly.

In addition to developing the type curves, a range of parameters affecting the performance of horizontal wells including vertical-to-horizontal permeability and the length of the horizontal well compared to the extent of the reservoir were reviewed. Porosity and drainage area size were found to have no affect on type curves. On the other hand, reservoir thickness and horizontal permeability were found to have minor impact on the shape of the type curves.

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Finally, I dedicate my work to my parents, and family members. Thank you very much for all your guidance, support and encouragement that you always have given me.

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NOMENCLATURE

P_R = Reservoir pressure (psia)

P_i = Initial Reservoir Pressure, (psia)

P_{wf} = Bottom-hole flowing pressure (psia)

P = Pressure (psia)

P_P = Pseudo-pressure, psi2/cp

a = Darcy flow coefficient, psi^2/ (cp)(Mscf/D)

b = Non- Darcy flow coefficient, psi^2/ (cp)$(Mscf/D)^2$

q_D = Dimensionless gas rate

q = Gas rate (Mscf/day)

t_D = Dimensionless time

t_{DL} = Dimensionless time with length

t_{DA} = Dimensionless time with area

t = time (days)

$2X_e$ = Width of reservoir (ft)

Ye = Length of reservoir (ft)

L = Length of lateral (ft)

L_D = Dimensionless length

G_p = Cumulative gas production (Mscf)

G_D = Dimensionless cumulative gas produced

G_{DL} = Dimensionless cumulative gas produced with length

G_{DA} = Dimensionless cumulative gas produced with area

A = Area (ft^2)

$m(p)$ = Real gas potential

h = thickness (ft)

k_H = horizontal permeability in x and y direction (mD)

k_v = vertical permeability in z direction (mD)

k = horizontal permeability (mD)

μ_i = Initial Viscosity (cp)

φ = Porosity (%)

Ct_i = Total initial compressibility (psi-1)

T = Temperature (^oR)

r_W = wellbore radius (ft)

r_{W_D} = Dimensionless wellbore radius

D_t = decline constant (days^{-1})

b = Arps decline – curve constant

z = Gas deviation factor, dimensionless

CHAPTER 1

INTRODUCTION

One of the most important requirements of a gas reservoir development is to estimate and forecast gas recoveries and production rates for individual wells or entire fields. Generally, only information about production rates versus time (production history) is available to initiate any evaluation of the reservoir on study. Different techniques have been developed in the past to obtain this information. Among these techniques, type curves have been found quite accurate to forecast gas well performance in absence of known reservoir parameters.

The utilization of these methods will depend on the economic risk associated with the forecast and the availability of the data necessary for the method being applied. Also, considerations such as time constraints, availability of certain models, or the familiarity of the engineer with different forecasting methods may be the governing factor in deciding which method might be applied.

Using of horizontal wells to produce natural gas has increased in the recent years, with significant production increase being reported (Sherrard, 1987). Given the fact that horizontal wells are viable alternative to vertically fractured wells; the need exists to understand fluid flow and production performance of horizontal completions.

The use of reservoir simulators to evaluate horizontal wells production performance at early stage of development is difficult, time consuming, and expensive due to lack of sufficient data. Type curves provide a simple and yet reliable alternative to simulation. However, there are no type curves available that represent the influence of the drainage area and its shape and reservoir parameters for instance thickness, porosity, permeability and pressure on the horizontal wells performance in conventional reservoirs.

CHAPTER 2

LITERATURE REVIEW

2.1 Conventional Decline Techniques

Conventional decline curve analysis is based on empirical equations developed by Arps (1945). Although his work was based on oil production data, the equations were also found applicable to volumetric dry gas reservoirs. Arps found three types of decline curves defined as exponential, harmonic, and hyperbolic decline. The general form of Arps's equation is:

$$q(t) = \frac{q_i}{(1 + bDt)^{\frac{1}{b}}} \qquad \text{.. (2.1)}$$

Where D_t is defined as the decline constant in days^{-1}, q_i is the initial gas flow rate in Mscf/D, q (t) is the flow rate to any time, t is time in days, and b is the depletion stem which defines any of the three type of decline according to its value. These forms of decline have a different shape according to the type of scale used to graph the available gas production.

Exponential decline is the simplest one and often used since many wells and fields follow a constant percentage decline over a great portion of their productive life, and only deviate from this behavior at the end of the productive life. Depending on the value of the decline exponent, b, Eq. 2.1 has three different forms. As shown in Figure 1, these three forms of decline, exponential, harmonic, and hyperbolic, have a different shape on Cartesian and semi-log graphs of gas production rate vs. time and gas production rate vs. cumulative gas production. Consequently, these curve shapes can help identify the type of decline for a well, and if the trend is linear, then it can be extrapolated graphically or mathematically to some future point.

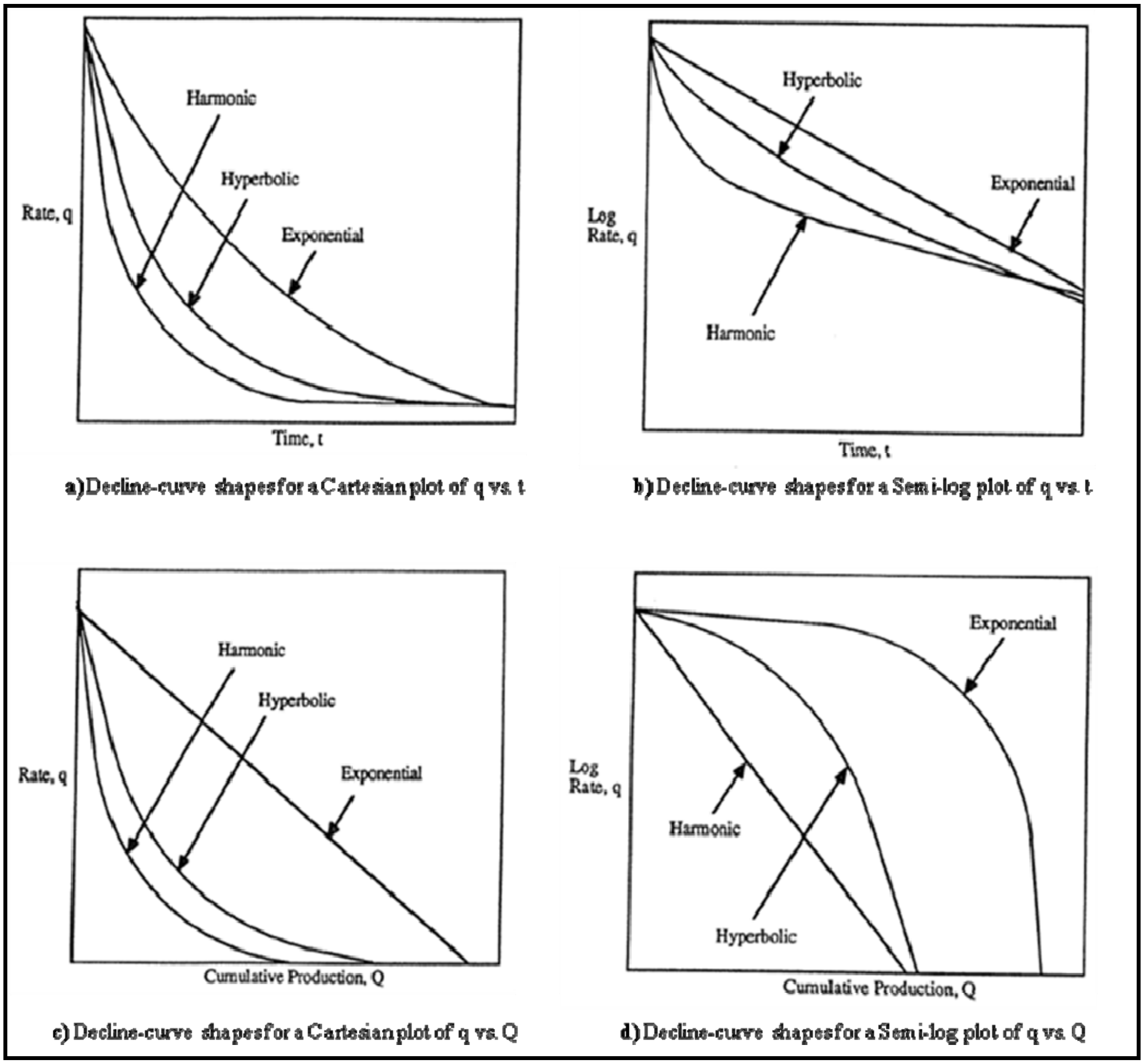

Figure 1 Decline-curve shapes for Cartesian and Semi-log plots of q vs. t and q vs. Q (Lee & Wattenbarger, 1996)

It is important to highlight that these decline forms have some assumptions to follow. Arp's equations assume that the well is produced at the same flowing pressure P_{wf}, constant reservoir drainage area, constant reservoir permeability and skin factor and any changes in the field development or production operation could change the future performance of a well and in that way will affect reserve estimations.

2.2 Type Curves

Unlike Arps's empirical decline curve analysis techniques, type curves are long-term constant pressure solutions based on theoretical considerations. The type curves are derived from models that simulate the production - decline behavior of a gas well against a constant back pressure, P_{wf} (Aminian, 2009). Basically; they are the general solutions to fluid flow problems. They are graphical representation of theoretical responses of an interpretation model that represents the well and reservoir being studied. Type curves are derived from solutions to fluid flow equations using specific initial and boundary conditions. The responses are usually presented in terms of dimensionless variables, e.g., dimensionless time (t_D), thus making them appropriate for general use (Gringarten, 1987). The type curves developed in this research are represented as gas production as a function of time. The type curves are not meant to replace reservoir engineering calculations but rather give the operator an idea how the well may produce throughout the life of the well.

Fetkovich (1980) introduced the concept of type curve matching. He combined the analytical constant terminal pressure solutions of the well diffusivity equation with the classical decline curve equations to yield a series of composite log-log dimensionless curves. The Fetkovich type curves are primarily developed for oil wells and as a result difficulties may be encountered when they are applied for gas wells. They do not account for the pressure loss due to high gas velocity near the wellbore (non-Darcy effects) and they do not consider changes in fluid viscosity and compressibility as reservoir pressure is reduced. Figure 2 shows an example of the production decline curves developed by Fetkovich. These curves are the result of the combination of the empirical - back pressure equation given by equation 2.2 and the gas material balance equation assuming the gas compressibility factor, z equals to 1.0 equation 2.3.

$$q = C(P_R{}^2 - P_{wf}{}^2)^n \quad \text{.......................................} \quad (2.2)$$

$$P_R = -(\frac{P_i}{G_i})G_P + P_i \quad \text{.......................................} \quad (2.3)$$

These curves assume a constant flowing pressure from a well centered in a circular reservoir with no flow boundaries. They also can be used for analyzing long-term gas production data from hydraulically fractured wells during the pseudoradial flow period and once the outer boundaries affect the pressure response.

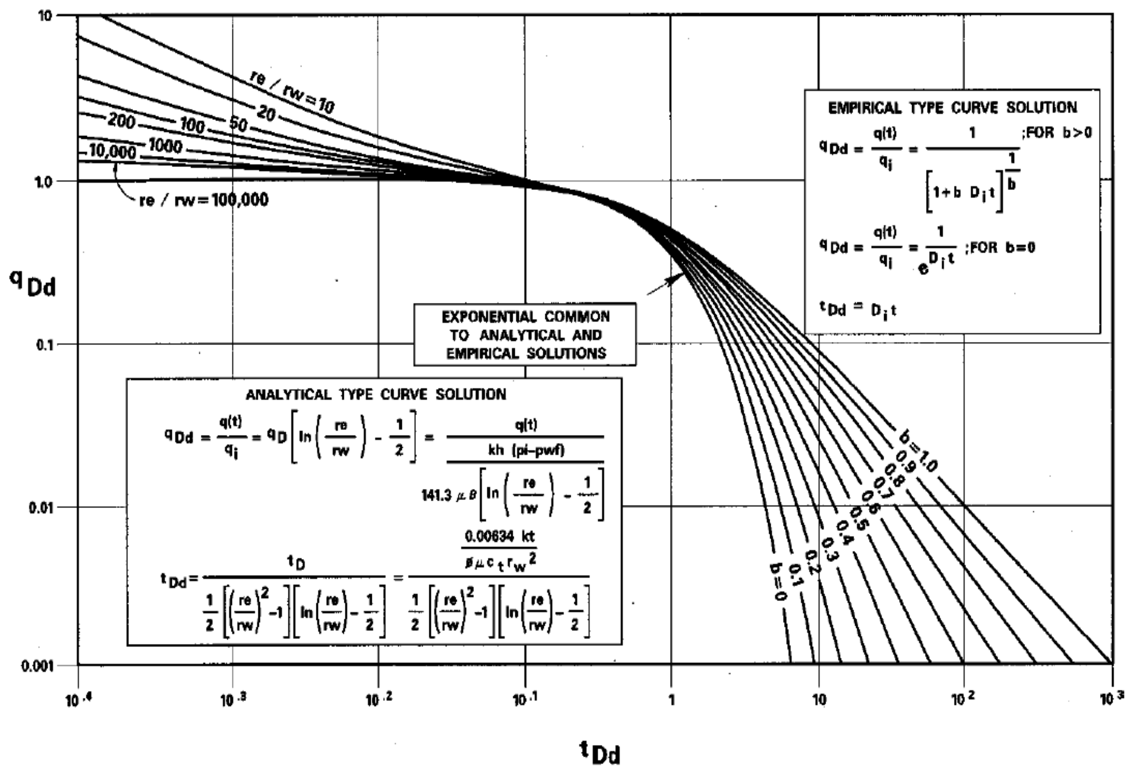

Figure 2 Fetkovich liquid system decline curves, (Fetkovich, 1980)

Smith (1980) extended Fetkovich type curves by varying the exponent "n", in equation 2.2, from 0.5 to 1.0 to account for the non-Darcy flow and generated many sets of type curves. At the same time, when dealing with numerous sets of type curves difficulties can be encountered in finding a unique match. In addition, equation 2.2 is only an empirical relationship and it has been shown that the value of "n" does not remain constant over the entire life of the well. Consequently, the forecasted flow rate based on a type curve, which treat "n" as a constant, was found to be not accurate.

Later, Carter (1984) generated a new set of type curves with a finite-difference reservoir model. These type curves improved the accuracy of the analysis by plotting functions that include the changes in the viscosity and compressibility of the natural gas with pressure. He considered the changes of the gas properties with the average reservoir pressure using a drawdown parameter (lamda). However, lamda must be calculated before a match can be made and the information needed to calculate lamda is not always available. Thus, the use of Carter's type curves was found to be complicated.

Farim and Wattenbarger (1985) proposed the use of the pseudo-time, to improve the application of Fetkovich type curves by allowing for the variation of gas properties with reservoir pressure. However, the disadvantage of this method was that estimate of gas in place is required to evaluate the pseudo-time.

However, all these authors have neglected the inclusion of non-Darcy flow in their calculations. A set of more representative curves were developed by Aminian et al. (1986) by combining the theoretical stabilized gas flow equation, equation 2.4 and the material balance for a volumetric gas reservoir, equation 2.5.

$$P_P(P_R) - P_P(P_{xf}) = aq - bq^2 \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(2.4)}$$

$$G_P = \frac{G_i(B_g - B_{gi})}{B_g} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(2.5)}$$

The model accounts for non-Darcy flow and dependency of gas properties on pressure and assumes constant reservoir parameters and operating conditions during the entire life of the reservoir.

Aminian et al. (1987) have discussed the violation of this assumption in practice due to changes in well spacing owing to infill drilling, back pressure changes due to compressor installation, and changes in skin factor due well stimulation. Thus, Aminian et al have accounted for these modifications in their equations developing relations between the type curve parameters and the producing formation characteristics.

Furthermore, Aminian et al. (1989) have developed type curves for cumulative gas production for horizontal wells producing from low permeability gas reservoirs. The effects of vertical-to-horizontal permeability and the ratio of the horizontal well length to the length of the reservoir were discussed.

In order to make a forecast using this technique; the history of gas production is matched with type curves until one is found, which most closely resembles the behavior of the actual data. Once the best possible match is found, the future production rates, gas reserves and reservoir parameters are evaluated from the chosen type curve. Figure 3 illustrates a graphical example of the type curve matching. Normally, the matched type curve differs from the plot of actual data only by a shift in coordinates. Another way of utilizing the type curve is to determine reservoir parameters when production history is available.

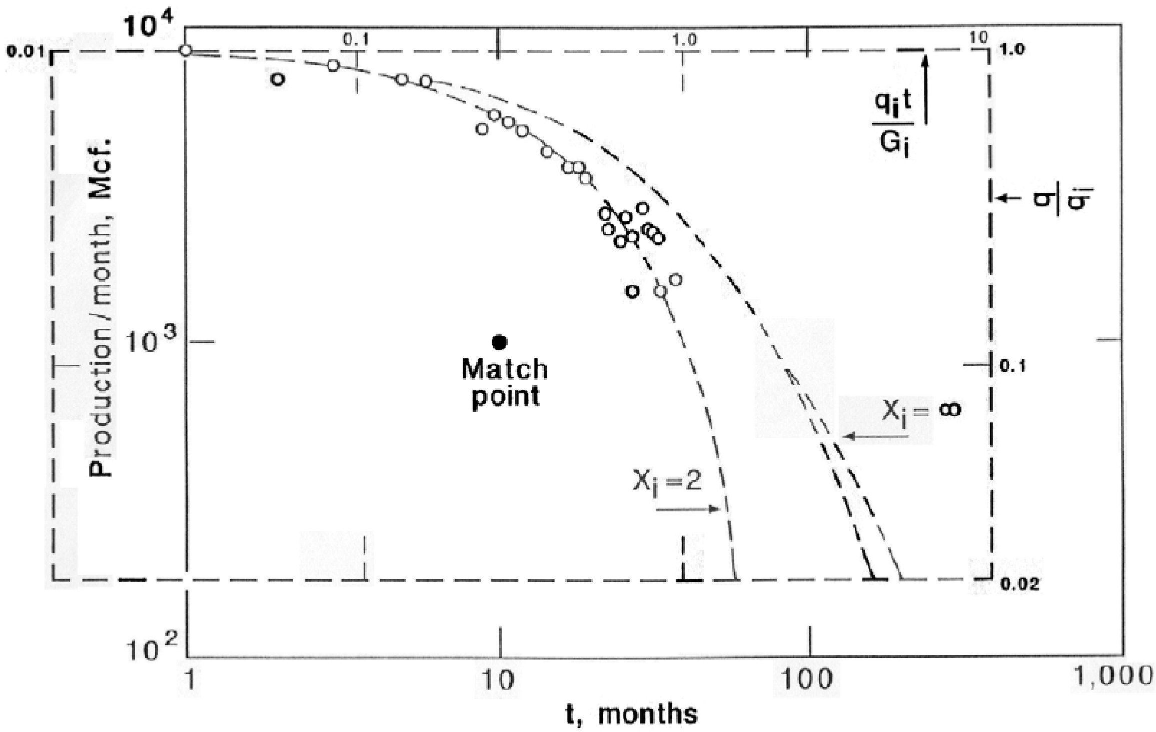

Figure 3 Graphical example of the type curve matching, (Aminian, 2009)

2.3 Horizontal wells

The use of horizontal wells for the production of crude oil and natural gas has accelerated during the past several years. Horizontal wells have been drilled in a variety of geologic settings including carbonates, sandstones, CBM and shales in order to access and produce hydrocarbons. Drilling a horizontal well can be achieved when a vertical hole is deviated to a horizontal direction so that it penetrates a maximum number of vertical rock fractures and penetrate a maximum distance of gas-bearing rock.

According to Clonts and Ramey (1986), Ozkan (1987), Joshi (1987 & 1988) and Economides et al. (1989), horizontal wells have been shown to be advantageous in: 1) naturally fractured reservoirs, 2) reservoirs with operational problems, e.g., gas or water coning, 3) relatively thin reservoirs, and 4) reservoirs with high vertical permeability. Horizontal wells are drilled to increase the surface area exposed for gas (fluid) withdrawal in order to increase well productivity.

Joshi (1988) found that, horizontal wells are not effective in very thick reservoirs (500 to 600 ft) and in formations with low vertical permeability. A decrease in vertical permeability results in an increase in vertical flow resistance for horizontal wells and a corresponding decrease in oil or gas production. Horizontal drilling techniques may be ineffective in layered reservoirs where several laterals (horizontal wellbores) would have to be drilled in order to access the oil and/or gas.

Still other disadvantages of horizontal well drilling include limitations in well completion and stimulation technologies. Another consideration of horizontal well drilling and completion operations is that the well costs are 1.4 to 3 times more than a vertical well. Hence, for an economic success, producible reserves from a horizontal well not only have to be proportionately large, but they should also be produced in a shorter time span than a vertical well (Joshi, 1991).

2.4 Horizontal wells Flow regimes

A horizontal well pressure analysis has shown that the horizontal well behaves as a vertical fracture with a fracture height equal to the wellbore diameter. The insignificant pressure drop observed in the horizontal wells indicates an infinite-conductivity for the flow in the wellbore. On the other hand, it is difficult to obtain infinite fracture conductivity in conventional fracture stimulation. Thus, horizontal wells would provide an alternative for conventional fracture stimulation (Clonts & Ramey, 1986, Ozkan et al., 1987 and Joshi, 1988).

Horizontal wells have unavoidable large wellbore storage effect and the horizontal section may extend for thousands of feet. As shown in Figure 4, in general, once the wellbore storage is stabilized, horizontal wells may exhibit three distinct regimes depending upon the well and reservoir geometry.

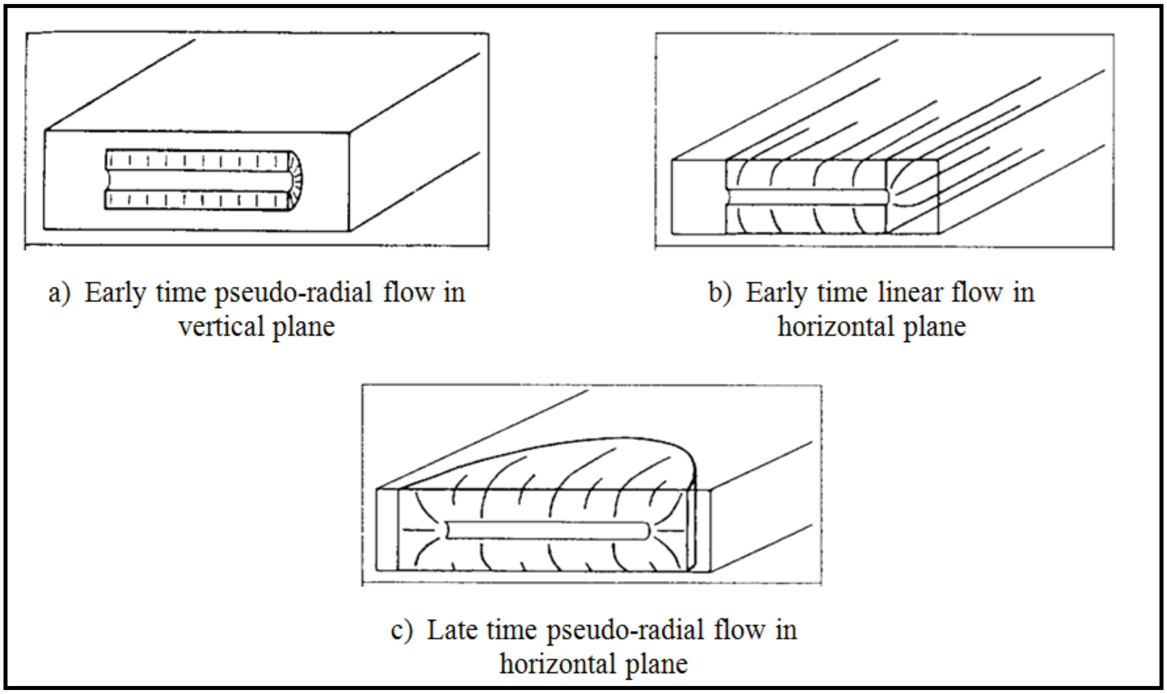

Figure 4 Three possible flow regimes in horizontal wells, (Joshi, 1991)

Analysis of horizontal well behavior indicates that initial flow is radial in a vertical plane. Ozkan et al. (1987) indicated that during this early-time flow period, the flow will be identical to that of vertical well in a formation with a thickness equal to the well length (L). This period ends when the effects of the closest boundary are felt; i.e., the top or bottom of the formation or flow across the well tips. If the formation height is small, or if k_v/k_H is small, this early radial flow may not be present. This flow regime is followed by a linear flow toward the well within the horizontal plane. Then, the early-time flow period is followed by a pseudo-radial flow period for infinite reservoirs in which the transient moves so far from the well that flow becomes radial again, but this time in the horizontal plane.

2.5 Dimensionless Variables

Two dimensionless variables have been shown to influence the response of horizontal wells: 1) the dimensionless well length (L_D), and 2) the dimensionless well radius (r_{wD}). The dimensionless well length relates vertical and horizontal permeability, formation thickness, and well length for a given reservoir-well situation. The dimensionless well radius relates the size of the drilled hole (well radius) to the length of the horizontal well. They are defined as followings (Aminian & Ameri, 1989):

$$L_D = \left[(L/2h)\sqrt{k_V/k_H} \right] \quad \text{.......................................} \quad (2.6)$$

$$r_{wD} = (2r_w)/L \quad \text{...} \quad (2.7)$$

Consistent with the published literature, these two dimensionless variables have been successfully used in this study to characterize the behavior of horizontal wells.

Aminian and Ameri (1989) have developed type curves for predicting horizontal well cumulative production. The dimensionless groups investigated were developed for predicting horizontal well production for an unconventional finite and infinite reservoir. For finite reservoirs, horizontal well productivity was presented in terms of dimensionless cumulative gas production and dimensionless time as a function of area as shown in equations 2.8 and 2.9, respectively:

$$G_{pDA} = \left[\ (9T)/(h\varphi\mu_i c_{ti} A\Delta m(p))\ \right] \times G_P \quad \text{……………..... (2.8)}$$

$$t_{DA} = \left[\ (0.006328k)/(\varphi\mu_i c_{ti} A)\ \right] \times t \quad \text{………………….... (2.9)}$$

Figure 5 illustrates the influence of the ratio of horizontal well length to reservoir length, penetration ratio ($L/2X_e$) into the long term production behavior of horizontal wells. The results showed that as the penetration ratio increases, flow changes from radial to more linear. With penetration ratio of one, flow would be linear in the horizontal plane, i.e., there would be no flow into the tips of the well.

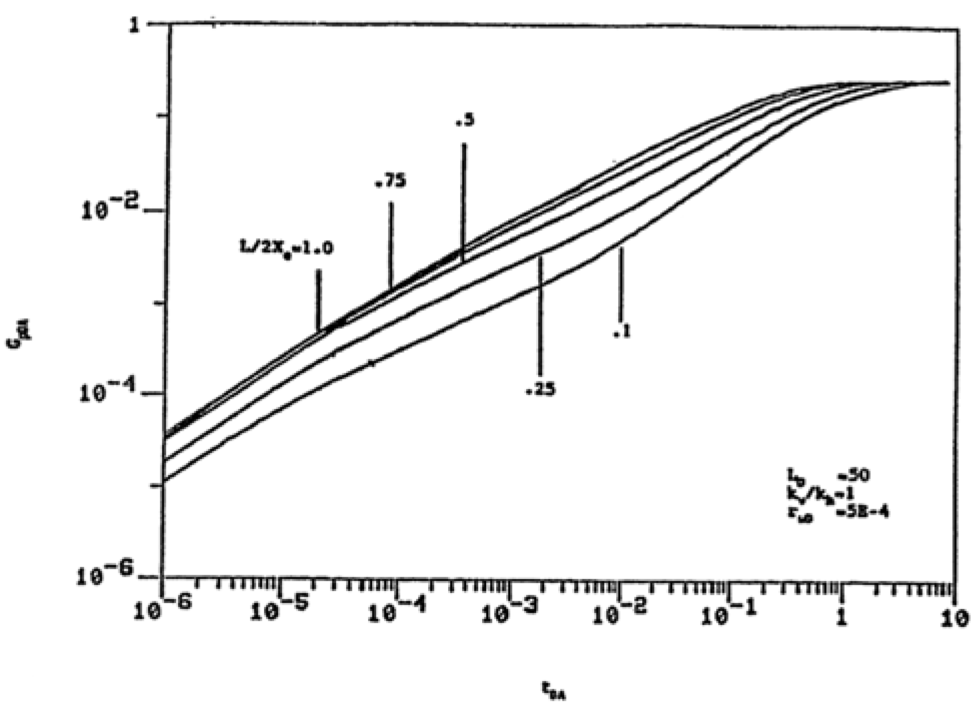

Figure 5 Dimensionless cumulative production responses for various well penetration ratios (L/2Xe), (Aminian & Ameri, 1989)

Figure 6 shows the comparison between the responses for rectangular and square areas with L_D and $L/2X_e$ held constant. The drainage area for a horizontal well after a long production period approaches an elliptical shape. Thus, the performance of a horizontal well in a rectangular drainage area is improved over a square area, whenever the direction of the well coincides with the longer side of the drainage area.

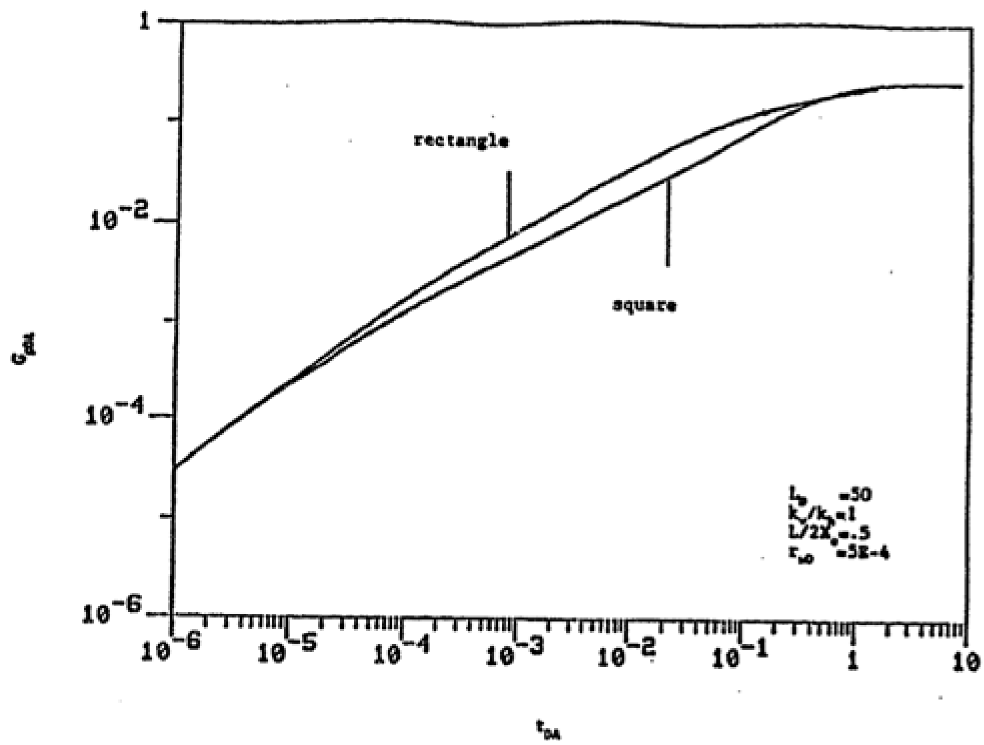

Figure 6 Dimensionless cumulative production responses for equivalent square and rectangular areas for L/2Xe = 0.5, (Aminian & Ameri, 1989)

For infinite reservoirs, horizontal well productivity was presented in terms of dimensionless cumulative gas production and dimensionless time as a function of well length as shown in equations 2.10 and 2.11, respectively:

$$G_{pDL} = \left[\ (36T) \big/ (h\varphi\mu_i c_{ti} L^2 \Delta m(p))\ \right] \times G_P \quad \text{……………..} \ (2.10)$$

$$t_{DL} = \left[\ (0.02532k) \big/ (\varphi\mu_i c_{ti} L^2)\ \right] \times t \quad \text{…..………………...} \ (2.11)$$

Figure 7 illustrates the influence of the dimensionless well length on the type curve for infinite reservoirs. At early times, significant pressure differences (high flow rates) can be induces with long wells in thinner reservoirs. Responses converge at later times. As shown, when L_D is greater than 10 the influence of the top and bottom boundaries becomes small and performance of a horizontal well approaches that of a fully penetrating infinite-conductivity fracture.

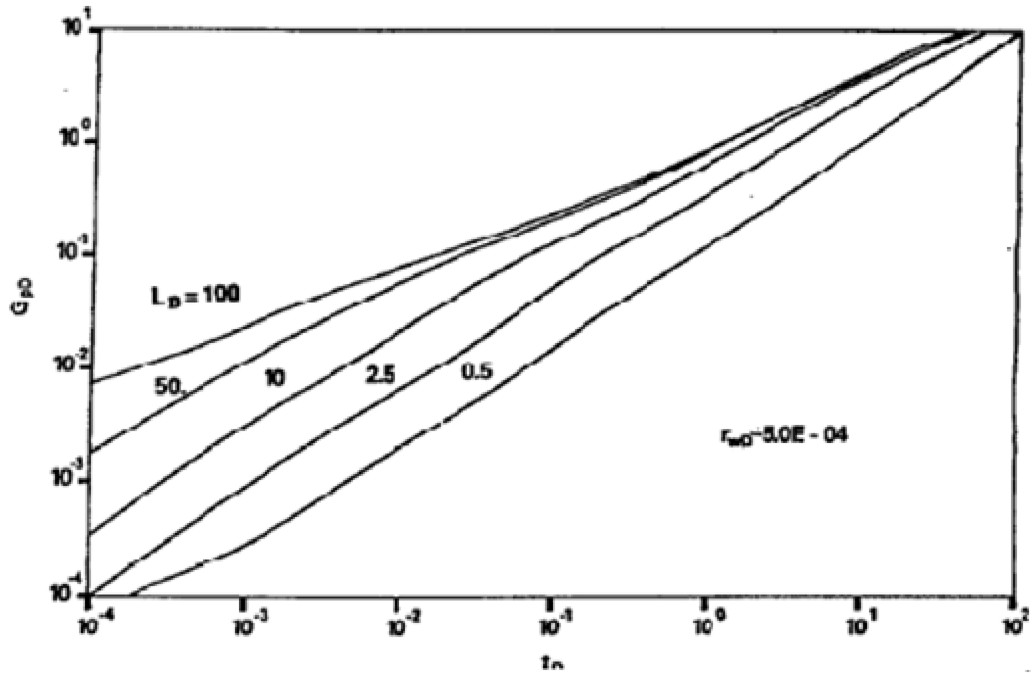

Figure 7 Dimensionless cumulative production responses for various L_D values for infinite reservoirs, (Aminian & Ameri, 1989)

2.6 Initial and Boundary Conditions

In general, two boundary conditions are considered in the analysis of horizontal wells. These boundary conditions are: 1) uniform flux, and 2) infinite conductivity (Ozkan et al., 1987). The constraint of uniform flux dictates that the production rate is constant with pressure varying along the length of the well. The assumption of infinite conductivity; however, yields a constant pressure in the horizontal wellbore.

Uniform flux solutions for horizontal wells yield a minimum pressure at the mid-length within the wellbore. However, reservoir fluids are usually produced out of one end of a horizontal well, thus the lowest wellbore pressure should occur at a well tip. This is not possible for a uniform flux boundary condition because fluid cannot flow from a central, low pressure point to a higher end-point pressure. Given these constraints, the assumption of infinite conductivity is the only viable boundary condition for a single horizontal wellbore (Joshi, 1987).

CHAPTER 3

OBJECTIVE AND METHODOLOGY

The primary objective of this research was to develop a reliable tool (production type curves) that can be used to predict the production performance of horizontal wells producing from natural gas conventional reservoirs particularly at the early stages of development where data is unavailable. In order to accomplish these objectives the following procedures were followed:

- Acquire conventional reservoir parameters from the literature.
- Develop a basic model to predict gas production profiles for horizontal wells.
- Validate developed model with published results.
- Evaluate the impact of various reservoir parameters on the type curves.
- Develop sets of production type curves for horizontal wells.
- Perform case study for type curves verification.

3.1 Natural Gas Reservoir Model Description

The gas reservoir simulator is a multi-dimensional model that solves one, two, or three-dimensional problems. Cartesian or polar coordinates can be specified in the simulator. Grid block dimensions in the X-direction, Y-direction, or Z-direction may be variable to facilitate area and cross-sectional studies. Boundary conditions are flexible in that any pressure or rate, as a function of time, may be imposed at any interior or boundary grid block. Additionally, the model may be operated in a radial mode to simulate a single production well. Complete reservoir heterogeneity is allowed in the sense that each finite-difference grid block can be assigned a unique value for each engineering variable i.e., permeability. However, in this study a homogeneous reservoir is considered.

Gas production responses for a horizontal well were developed using a finite-difference natural gas simulator, Schlumberger Eclipse Reservoir Simulator. The production responses are presented in terms of dimensionless gas production and dimensionless time for general application. In order to account for pressure dependent gas properties, Al-Hussainy et al. (1966) manipulated the pressures in terms of the real gas potential (pseudo-pressure).

Literature review was conducted to identify the range of parameters to be used in the base model for the study. The "Completions Modeling Tool" template, Eclipse office, was used in this study to set up the reservoir simulation model (Eclipse, 2007). This tool allows the user to easily generate the reservoir, build the completion configurations and evaluate results quickly, using an auto generated graphics for result evaluation. This template uses a single porosity reservoir model.

The "Completions Modeling Tool" template workflow is described as following: in the first workflow, the general "model definition" has to be defined i.e., single phase gas flow. By default, a single set of initial conditions is assumed to apply to the entire reservoir. The second workflow field provides access to the "reservoir description" which was used to input the reservoir characteristics including reservoir layers dimensions and location with respect to sea level.

After that, the "rock properties" data entry panel will be activated to specify the rock properties i.e., porosity, x, y, and z direction permeability and compressibility for each layer of the model. Then, a workflow "well data entry" page was used to define the well location in terms of its deviation surveys coordinates. Following to the well data entry, a workflow to define the well events was used to input the "production characteristics" for the well i.e., production or perforation of the well and constrain the BHP. Then, the "fluid properties" workflow data entry was used to define the PVT and fluid properties for the system. All of the required properties are calculated automatically by means of correlations.

Before the model was run, “a simulation controls” workflow data entry page was used to set the simulation gridding controls for the system. Finally, “run simulation” workflow was used to run the model and generate the output from the simulator which will be automatically loaded and a number of graphical displays automatically created and ready to view and evaluate.

3.2 Base Model Development and Assumptions

Development of the production responses for a horizontal well involves defining the appropriate reservoir-well geometry, initial and boundary conditions, and simulating the production of natural gas at a constant flowing pressure.

Production responses were generated in this investigation using a rectangular coordinate system with a length to width ratio of 2 to 1. The general solutions assume that the horizontal well is located in the center of the reservoir (h/2) and parallel to the bottom and top of the reservoir. Figure 8 shows the reservoir geometry considered in this study and the vertical position of the horizontal well. A homogenous, single-phase gas flow and single-porosity multi-layer reservoir (5-layers) model is considered in this research to account for the vertical permeability effect. Table 1 lists the base case reservoir parameters. The permeability values for the vertical and horizontal direction are different at a constant ratio k_z / k_x 1:3. The permeability values for x and y directions are the same ($k_x = k_y$).

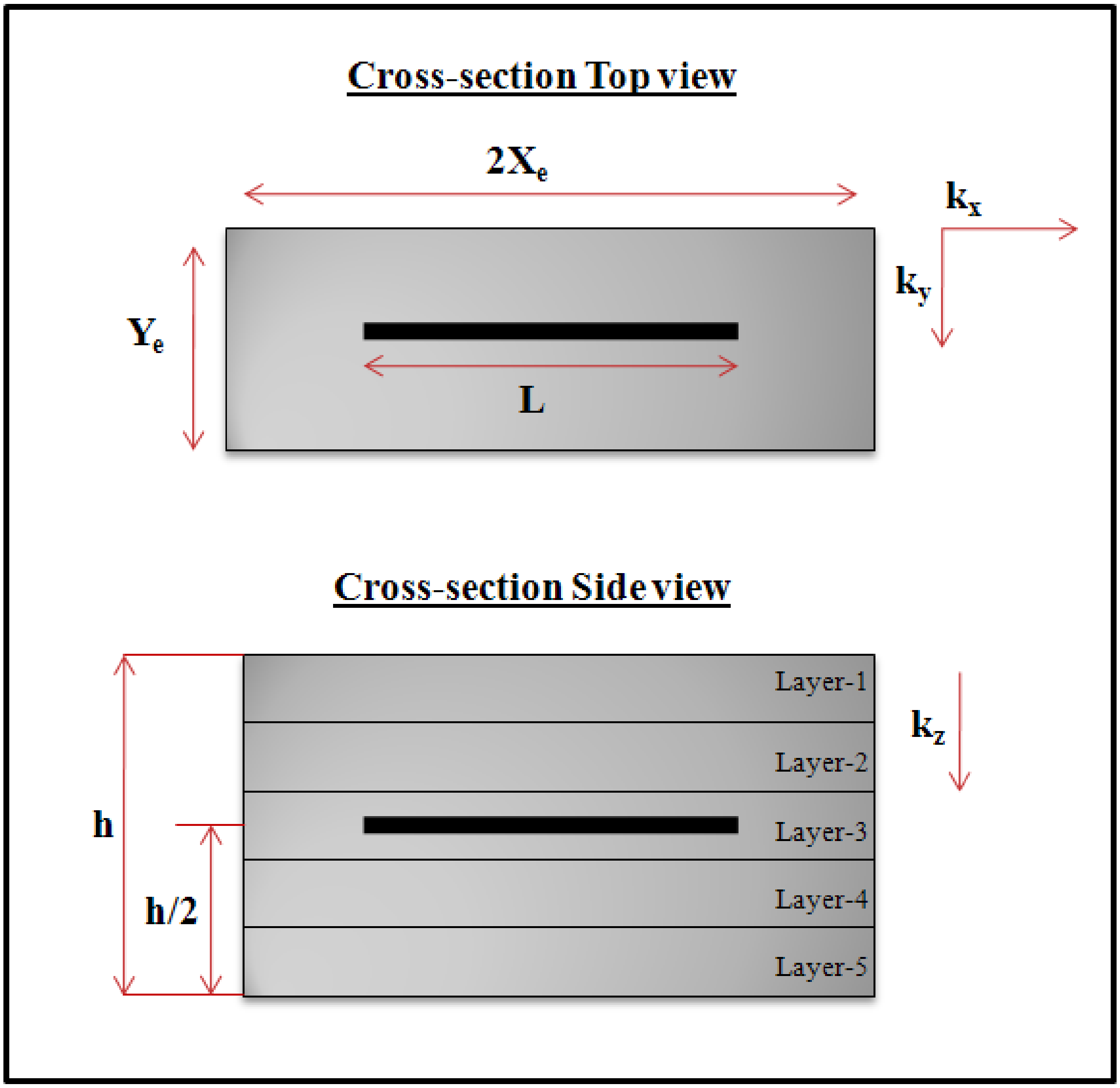

Figure 8 A Schematic of horizontal well in rectangular drainage system

Table 1 Input data for the base case

Input Parameters	Value
Period of Production (years)	30
Fluid Type	Dry Gas
Porosity Model	Single Porosity
Porosity (%)	10
Model Geometry	Multilayer reservoir (5-layers)
Grid Size (ft x ft)	100 x 100
Reservoir Area (acres)	46
Shape	Rectangle
Reservoir Depth (Top)(ft)	3,000
Reservoir Thickness (ft)	20
Reservoir Length (2Xe) (ft)	2,000
Reservoir Width (Ye) (ft)	1,000
Well Length (L) (ft)	1,500
X-direction Permeability (mD)	0.1
Y-direction Permeability (mD)	0.1
Z-direction Permeability (mD)	0.03
Reservoir Pressure (psia)	1,500
Bottom Hole Flowing Pressure (psia)	750
Water Saturation (%)	20
Reference Temperature (^{o}F)	100
Gas Gravity	0.72
Wellbore Dim. (ft)	0.5

3.3 Base Model Verification

The developed base model was verified with a published data in the literature. Figure 9 shows the dimensionless cumulative production responses for various well penetration ratios ($L/2X_e$) for the base model which replicated with published results.

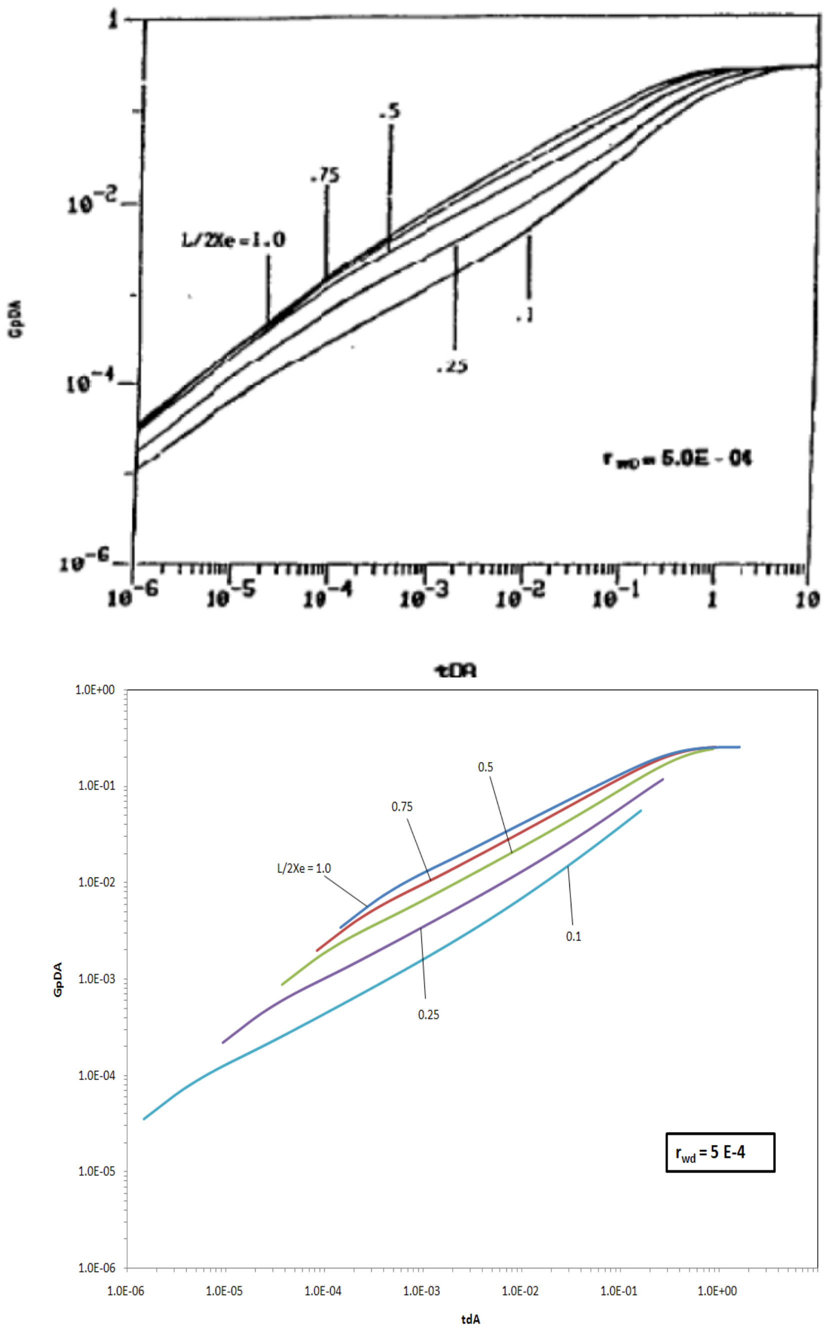

Figure 9 Base model results replicated with literature results, (Aminian & Ameri, 1989)

3.4 Dimensionless Variables and Model Parameters Ranges

The well penetration ratio ($L/2X_e$), the dimensionless parameter *Xi* and dimensionless well length (L_D) are the major parameters in the production analysis development. In order to establish the unique type curves, the impact of the reservoir parameters were investigated. It was found that two different sets of type curves will be needed due to having two distinct flow regimes. Table 2 listed all parameter ranges and values used to develop these type curves.

The dimensionless well lengths investigated are 10, 50 and 100. These ranges were selected to ensure production solutions for horizontal wells drilled in typical reservoir-well situations. Very low L_D situations are not advantageous for horizontal well drilling. Well penetration ratios ($L/2X_e$) of 0.25, 0.5 and 0.75 were considered in this investigation. The permeability values for the vertical and horizontal direction were changed at a constant ratio k_z / k_x 1:3 ($k_x = k_y$).

Different type curves were generated by varying the value of the dimensionless parameter *Xi,* as defined in equation 3.1, for an initial reservoir pressure of 1500 psia and for the three different $L/2X_e$ ratios 0.75, 0.5 and 0.25. The dimensionless parameter *Xi* values investigated are 1.1, 1.25, 1.5, 2.0 and 5.0.

$$X_i = \frac{\left[\frac{P}{z}\right]_i}{\left[\frac{P}{z}\right]_{wf}} \qquad \text{……………..…………………………….. (3.1)}$$

Where,

P_i = Initial reservoir pressure, psia

P_{wf} = Bottom-hole flowing pressure psia

Table 2 Summary of the parameters used in the simulation

Parameters	Ranges	Used Values
Reservoir Shape	Rectangular	Rectangular
Well Penetration ratio ($L/2X_e$)	0.25-0.75	0.25, 0.5 & 0.75
Dimensionless Parameter, X_i	1.1-5.0	1.1, 1.25, 1.5, 2.0 & 5.0
Dimensionless Well Length (L_D)	10-100	10, 50 & 100
Reservoir Area (acres)	46-636	46, 56, 141, 160, 128, 344 & 636
Reservoir Thickness (ft)	10-100	10, 20, 30, 40, 50, 60, 70, 80, 90 & 100
Horizontal Permeability (mD)	0.001-5	0.001, 0.01, 0.1, 1, 3 & 5
Porosity (%)	2-30	2, 5, 10, 20 & 30

3.5 Gas Production Simulations for Type Curve Development

One set of type curves will not satisfy the different flow regimes that occur in the case of production from horizontal well. As stated earlier in this report, two different sets of type curves will be needed to represent the horizontal well production responses. The first sets of type curves will represent the early part of well production. Once the next flow regime is reached another set of type curves will be used to predict the rest of the production for the well life. Equations 2.6, 2.7, 2.11, 3.1 and 3.2 were used when developing the type curves.

$$q_D = \left[\ (1424T)/(kh\Delta m(p))\ \right]\times q \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (3.2)$$

Once the reservoir-well geometry and the initial and boundary conditions were defined, 80 simulation runs at a constant flowing pressure were completed, excluding sensitivity cases. Values of dimensionless gas production were developed as a product of the simulated gas production volumes and the coefficient shown in equation 3.2.

The first sets of type curves were generated for the early part of well production, when parameters were changed with unchanged (L_D) value while changing one variable at a time. For example, to evaluate the effect of drainage area changes on the type curves, the dimensionless well length (L_D) was kept as a constant value of 10 and the value of the drainage area was varied, 46 acres, 56 acres, 141 acres,…etc. The same thing was done to the other parameters namely, reservoir thickness, horizontal permeability and porosity.

The second sets of type curves were generated for the late part of well production, when parameters were changed with the same ($L/2X_e$) ratio while changing one variable at a time. For example, to evaluate the effect of horizontal permeability changes on the type curves, the well penetration rations ($L/2X_e$) was kept as a constant value of 0.75 and the value of the horizontal permeability was varied as 0.001 mD, 0.01 mD, 0.1 mD, 1 mD,…etc. The same thing was done to the other parameters, namely, reservoir thickness, reservoir drainage area and porosity. All results are presented and discussed in the following chapter.

3.6 Case Study for Verification

To evaluate the reliability of the gas production type curves, a case study was performed. A set of reservoir characteristics summarized in Table 3 were used as inputs into the reservoir simulator to generate the production history. These production histories were used to compare against the predictions predicted from the type curves.

Table 3 Input data for Case Study

Parameters	Value
Reservoir Area (acres)	50
Porosity (%)	10
Reservoir Depth (Top)(ft)	5,000
Reservoir Thickness (ft)	43
Horizontal Permeability (mD)	0.1
Reservoir Pressure (psia)	2,000
Bottom Hole Flowing Pressure (psia)	1112
Reservoir Length (2Xe) (ft)	2,080
Reservoir Width (Ye) (ft)	1,040
Well Length (L) (ft)	1,560

CHAPTER 4

RESULTS AND DISCUSSIONS

4.1 Evaluating Different Dimensionless Groups for Type Curves Development

Three dimensionless variables have been shown to influence the gas production type curves, namely, the dimensionless well length L_D, the well penetration ratio $L/2X_e$ and the dimensionless parameter *Xi*.

4.1.1 Impact of L_D on the Type Curves

Horizontal well performance is significantly affected by L_D at early production times. Figure 10 shows the impact of L_D on the production responses for a rectangular area of 82 acres with a constant $L/2X_e$ ratio of 0.75. When the value of L_D reaches 50, no impact on the type curves was observed.

4.1.2 Impact of L/2Xe on the Type Curves

Figure 11 demonstrates the significant effect of $L/2X_e$ on the shape of the type curves at late production times for a rectangular area of 46 acres. The results show that as the ratio of the well length to the reservoir length decreases, type curves shifts to the right.

4.1.3 Impact of *Xi* on the Type Curves

Figure 11 shows different type curves generated by varying the values of the dimensionless parameter *Xi,* as defined in equation 3.1, for an initial pressure of 1500 psia and L/2Xe = 0.75, 0.5 and 0.25. Horizontal well performance is significantly affected by *Xi* at late production time. As is observed, *Xi* parameter defines the pressure drawdown exhibited by the well. As the pressure drawdown is larger the curves shift to the right due to the larger gas production at higher differential pressure.

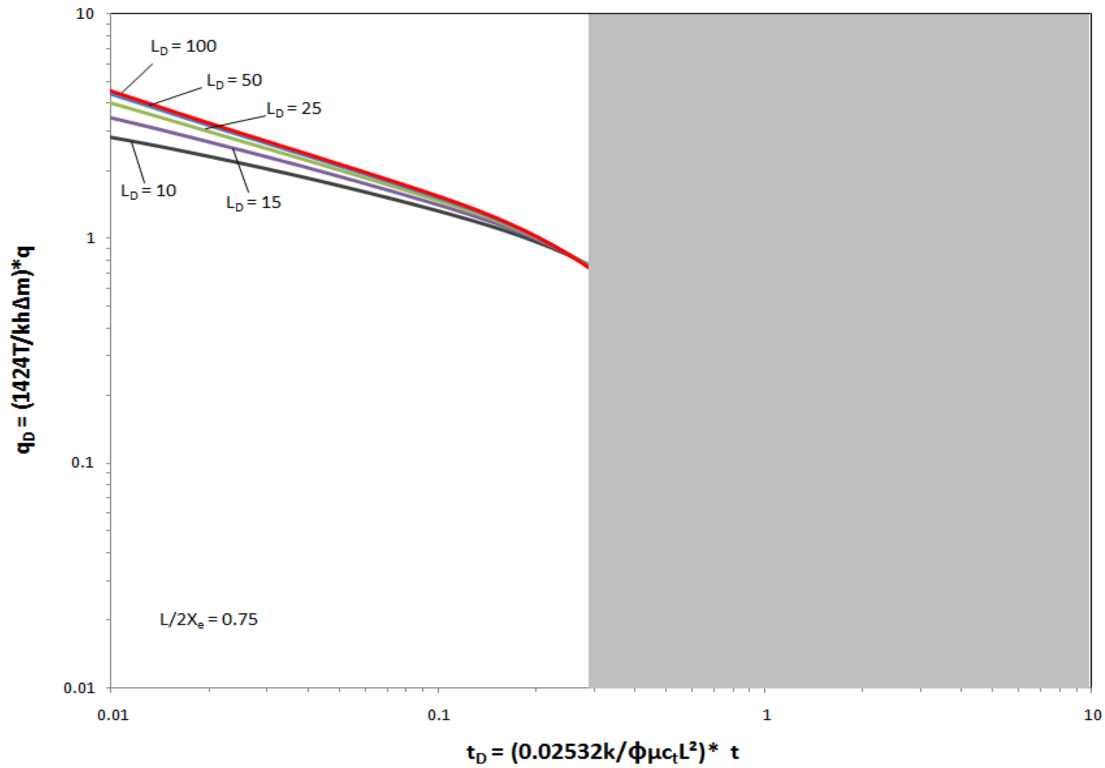

Figure 10 Impact of L_D on the type curves

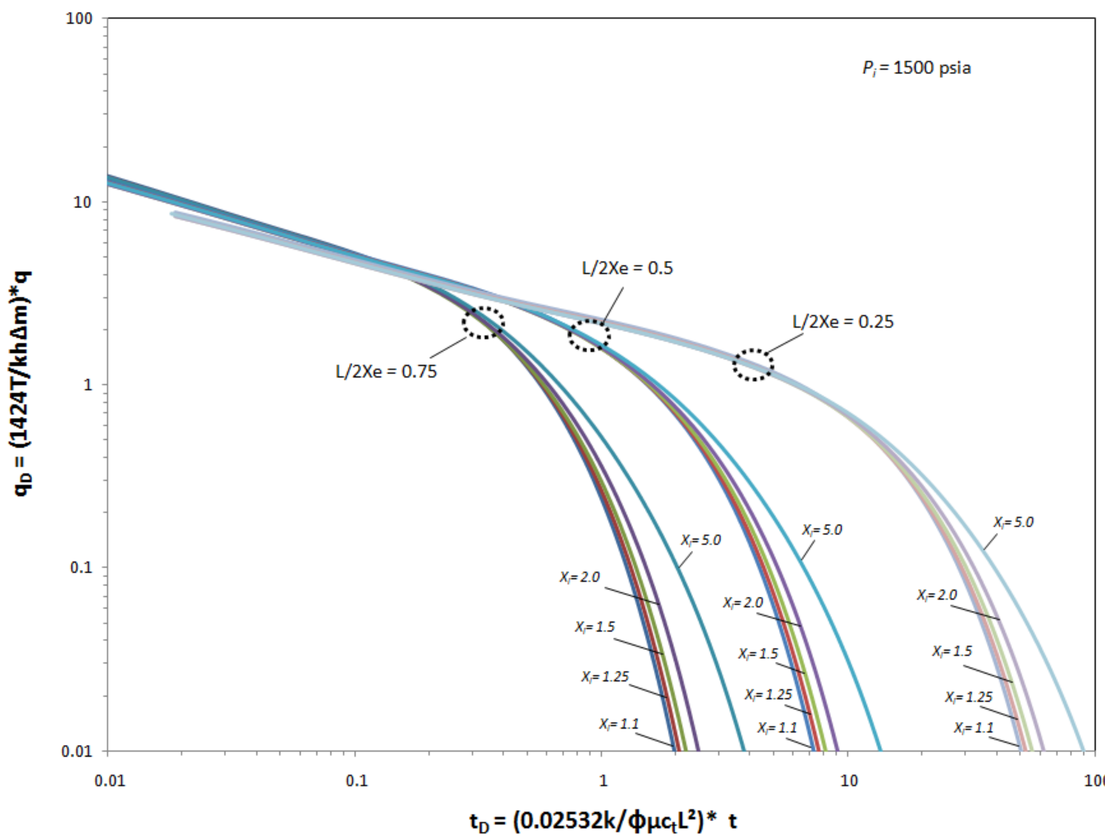

Figure 11 Impact of L/2Xe and *Xi* on the type curves

4.2 Impact of Different Parameters on Type Curves

Variables and parameters that affect the productivity of horizontal wells are discussed in the following subsections. Figures 12 thru 18 illustrate the impact of different parameters into the gas production type curves.

4.2.1 Impact of Drainage Area

The drainage area was varied from a range of 46 acres to 636 acres. Respectively, Figure 12 and 13 show the production responses for various drainage areas for both the early and the late production times. It is obvious that drainage area variation has no impact on the type curves for both the early and the late production type curves.

4.2.2 Impact of Porosity

The porosity was varied from a range of 2% to 30%. Figure 14 depicts the production responses of the porosity change for both the early and the late production times. There is no effect on the type curves when the porosity values were varied for both the early and late production periods.

4.2.3 Impact of Horizontal Permeability

The horizontal permeability was varied from a range of 0.001 mD to 5 mD. Figure 15 shows the production responses of the horizontal permeability change for the early production time. The results indicate that the effect of variation on the horizontal permeability on type curves is minimal at the early part because of the vertical permeability effect. Figure 16 illustrates the minimal effect of the horizontal permeability on the type curves for the late production times.

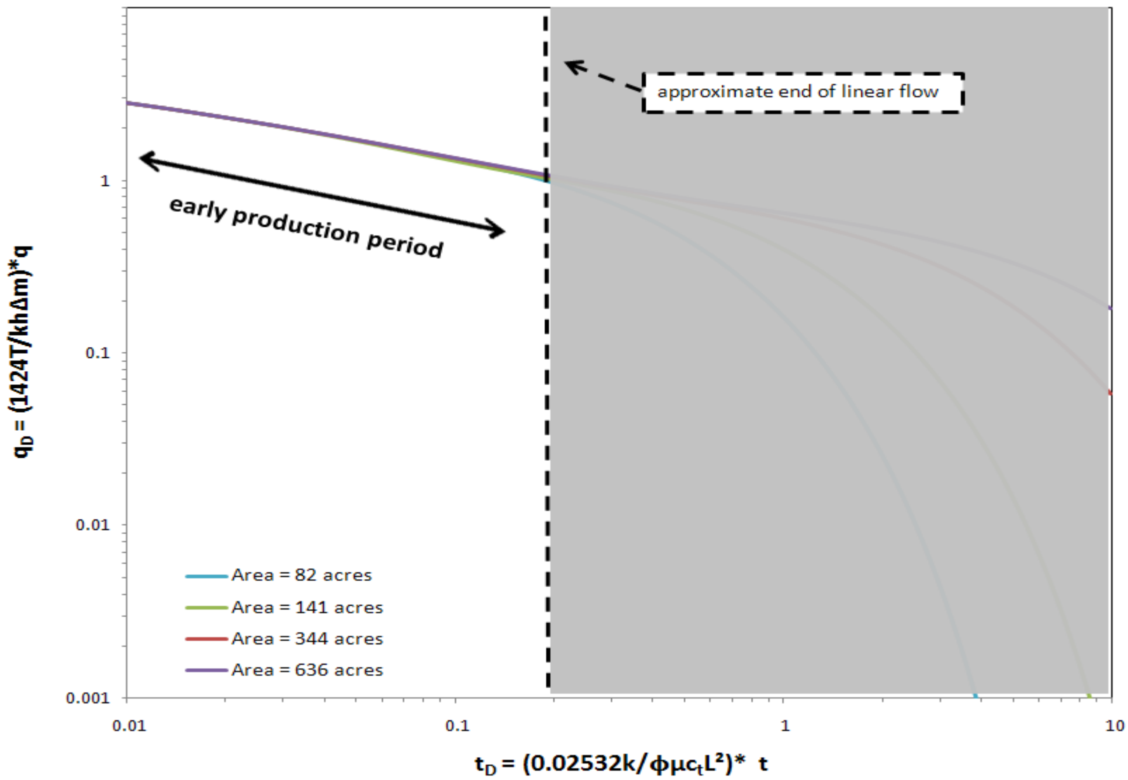

Figure 12 Impact of drainage area for $L_D = 10$ (early production)

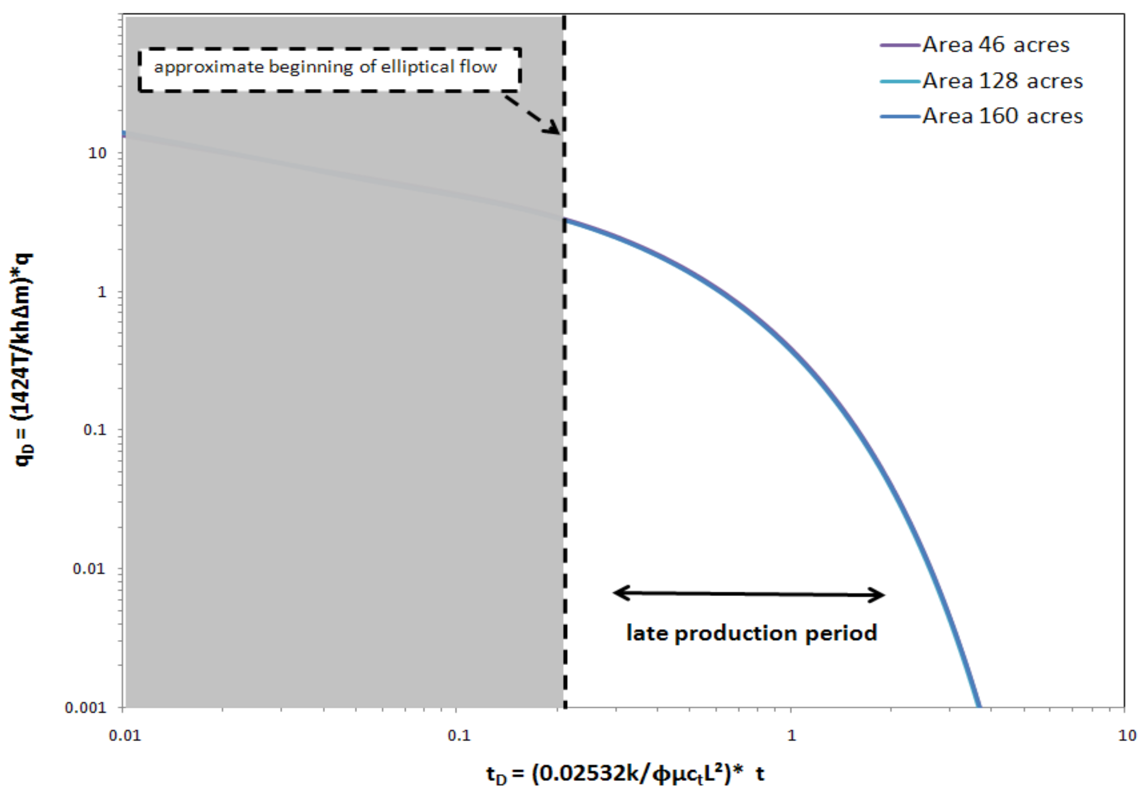

Figure 13 Impact of drainage area for $L/2X_e = 0.75$ (late production)

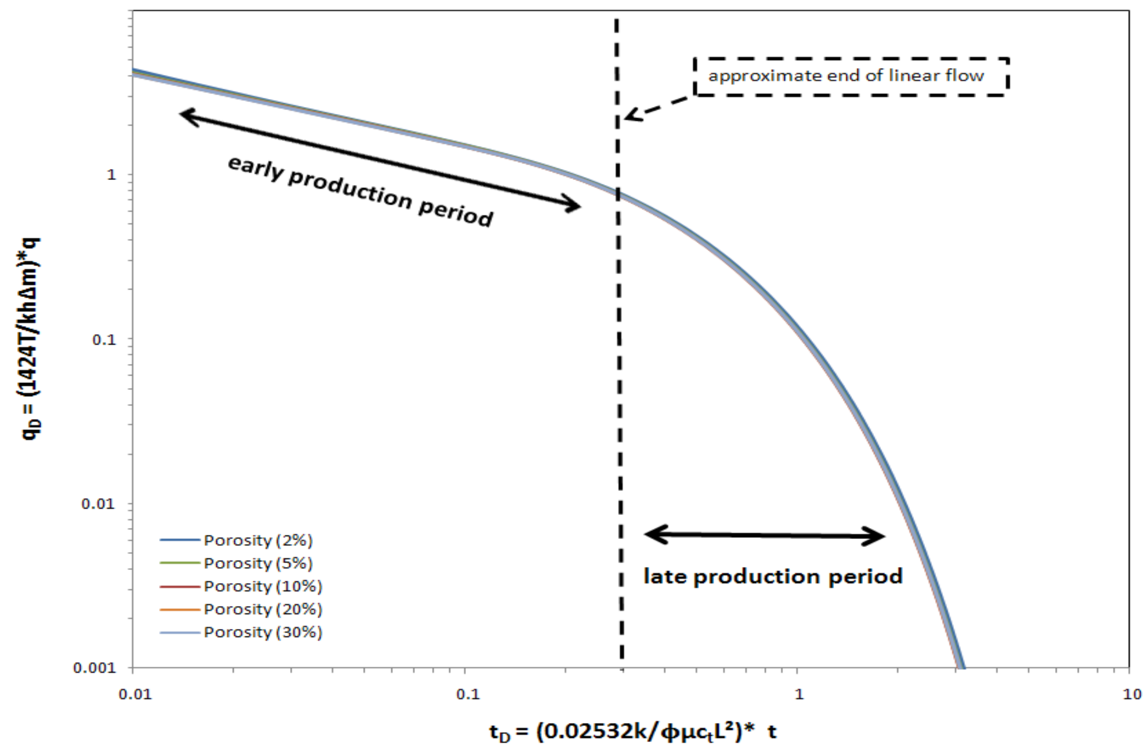

Figure 14 Impact of porosity for the early and late production periods

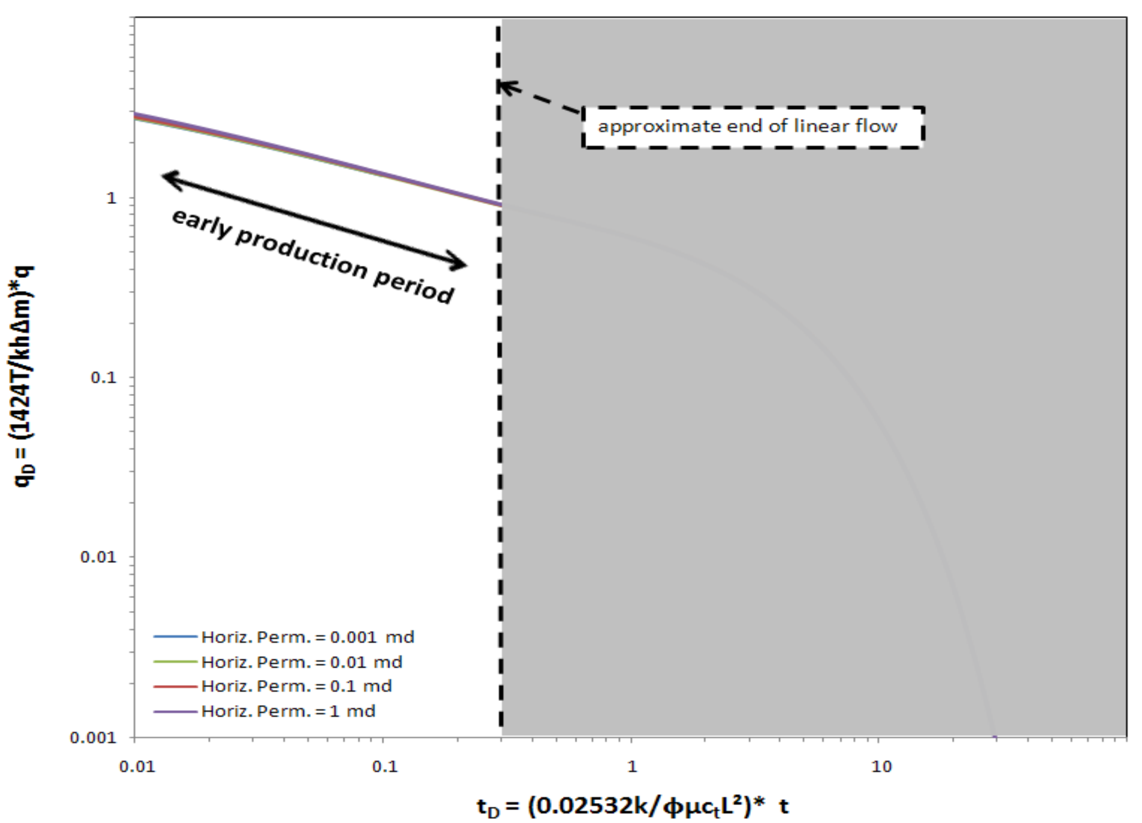

Figure 15 Impact of horizontal permeability for L_D = 10 (early production)

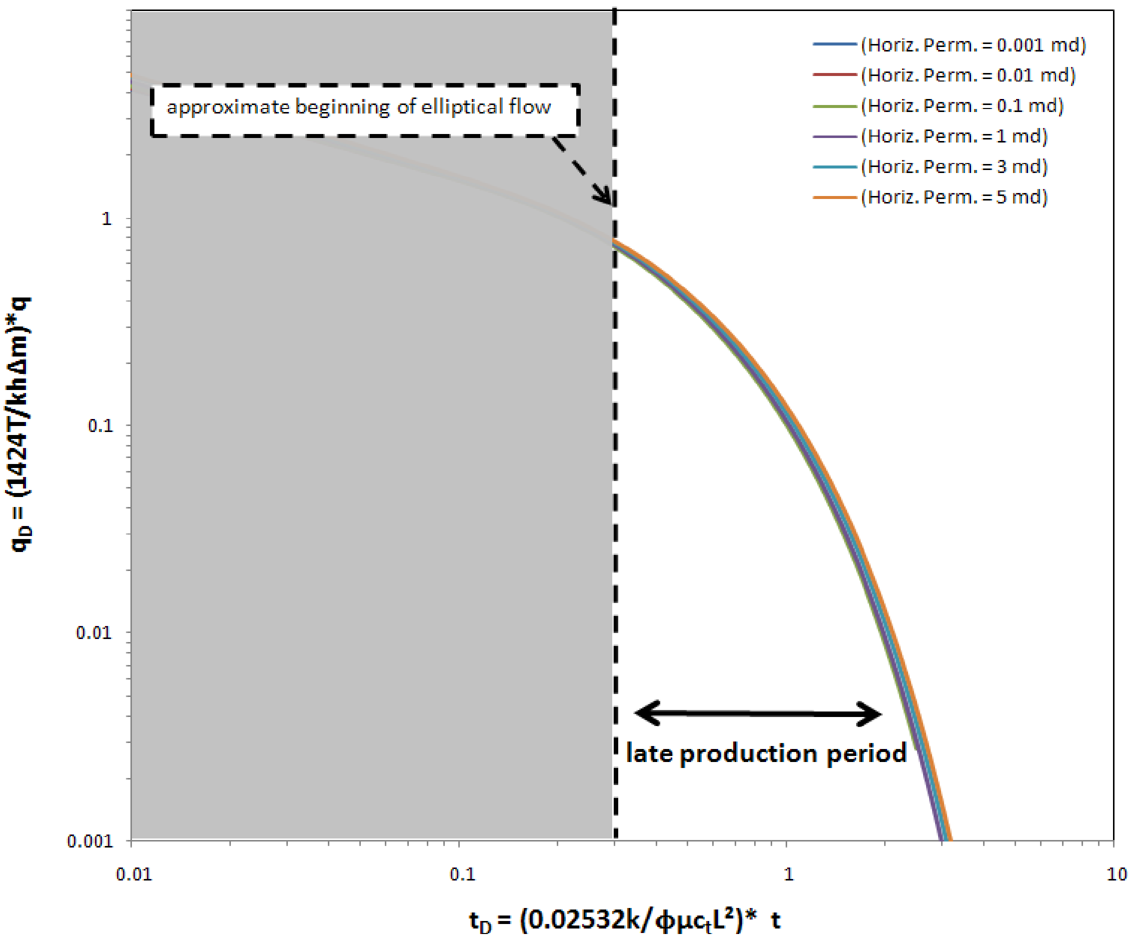

Figure 16 Impact of horizontal permeability for $L/2X_e = 0.75$ (late production)

4.2.4 Impact of Reservoir Thickness

The reservoir thickness was varied from a range of 10 ft to 100 ft. Respectively, Figure 17 shows the production responses of the thickness change for the early production time. Thickness change has the same effect on the type curves as the horizontal permeability change does. The results point to an insignificant effect when the reservoir thickness values were varied for both the early and late production periods. Figure 18 illustrates the effect of the reservoir thickness on type curves for the late production times.

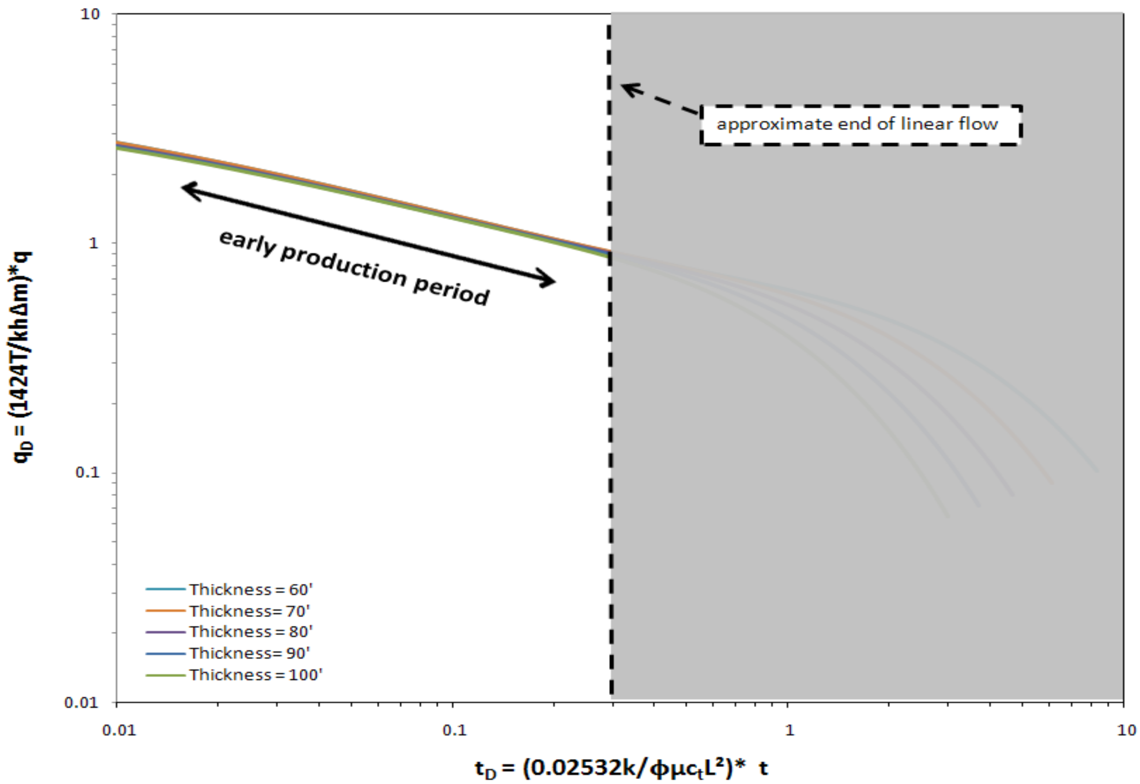

Figure 17 Impact of thickness for $L_D = 10$ (early production)

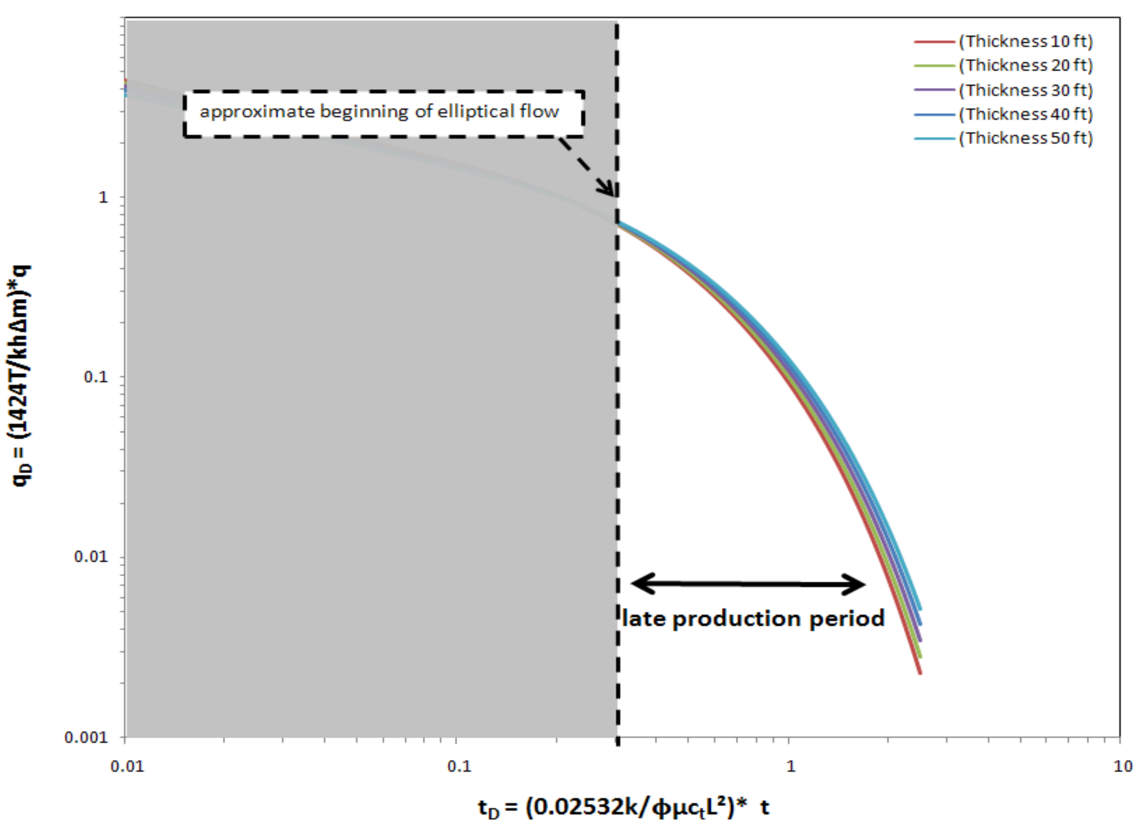

Figure 18 Impact of thickness for $L/2X_e = 0.75$ (late production)

4.3 Comparison of Predicted Gas Production

Figure 19 shows the gas production predicted from the developed type curves against the simulation results of the case study. The results indicated that, the predicted gas production rate from the type curves closely match production from the simulation results of the case study concluding the type curves developed can provide reliable results.

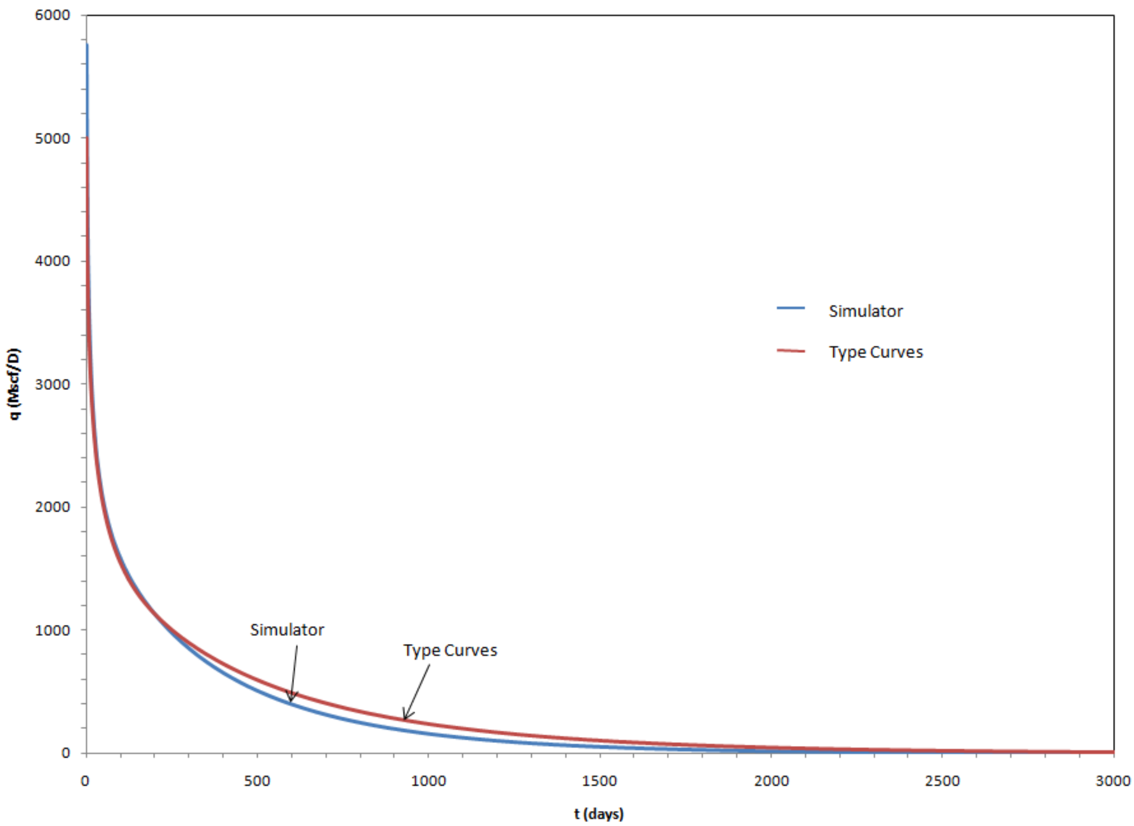

Figure 19 Comparison of the predicted gas production (case study vs. type curves)

CHAPTER 5

CONCLUSIONS AND RECOMMENDATIONS

Horizontal well technologies have advanced significantly in recent years making this drilling and completion alternative appropriate for many oil and gas ventures. The main purpose of this research was to develop a set of type curves that could be used to evaluate and predict production data for conventional horizontal wells. Reservoir parameters were considered in this research to determine the impacts on production. Based on the results, the following conclusions and recommendations were made:

1. Two different sets of type curves are needed due to having two distinct flow regimes for horizontal gas wells in conventional reservoirs.

2. Three dimensionless variables have been shown to influence the gas production type curves, the dimensionless well length L_D (early production), the well penetration ratio $L/2X_e$ (late production) and the dimensionless parameter *Xi* (late production).

3. Drainage area and porosity had no effect on type curves for both early and late production periods.

4. Reservoir thickness and horizontal permeability changes had a minimal effect on type curves for both early and late production periods.

5. Reservoir thickness has a sensitive effect on the type curves. Thus, it is recommended to obtain an accurate reservoir thickness reading before matching the type curves.

It is recommended to evaluate the impact of different reservoir parameters and develop similar type curves for both naturally fractured gas reservoirs and hydraulically fractured horizontal wells. The need for forecasting reliable gas recoveries for these two fields has increased in recent years.

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